U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

CLIFFS

Enabling Production of Low Carbon Emissions Steel through CO_2 Capture from BF Gases (FE0031937)

Presentation on Pre-FEED Study Report

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Outline

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Background and Objectives of the Study

1

The steel industry is responsible for ~7-9% of overall carbon emissions worldwide

2

The blast furnace is the most carbon intensive operation in ISPs, emitting 1.6 – 2.1 tonne CO_2 per tonne of hot metal.

3

The project aims to capture and sequester up to 2.8* mpta† CO_2 emissions from the blast furnace, which represents ~ 80% of CO_2 emissions from the available BF gas

* Gross CO_2 capture

4

Using a novel fuel conversion and carbon capture scheme, the project aims to capture and sequester CO_2 at optimal cost structure

5

Produce hydrogen rich fuel for use in the steel plant today with optionality to produce pure hydrogen in the future

†mtpa : Million metric ton per annum

CCU Design Rationale – Flexible, Scalable Design for CO_2 Capture with H_2 Extraction

1 **Carbon Capture at scale from blast furnace** with energy transformation for low carbon H_2 rich fuel

2 **Flexibility of Design** for 2.8 mtpa CO_2 capture, while optimizing and extracting H_2 rich fuel

3 **Optimizing CO_2 Capture Economics** (Capex and Opex) based on train capacity, CO_2 concentration, related gas conditioning and with 95% capture efficiency

4 **Flexibility of Design** to route conditioned gas blends to maintain operational flexibility and reliability

5 **Optionality in Design** to extract hydrogen by additional refinement of H_2 rich fuel for use in steel plant or for auxiliary use in future

Water Gas Shift Reactor Design – Higher Capture Volume, Optimized CCU Island, Lower Cost, H_2 Optionality

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1. **Increasing CO_2 Capture from blast furnace from 1.57 mtpa** with no shift **to 2.8 mtpa*** with 78% shift in water gas shift reactor

2. **Higher CO_2 Concentration in conditioned gas (22% to 33%)** allowing better capture efficiency at CCU Island and offering advantage of **economies of scale**

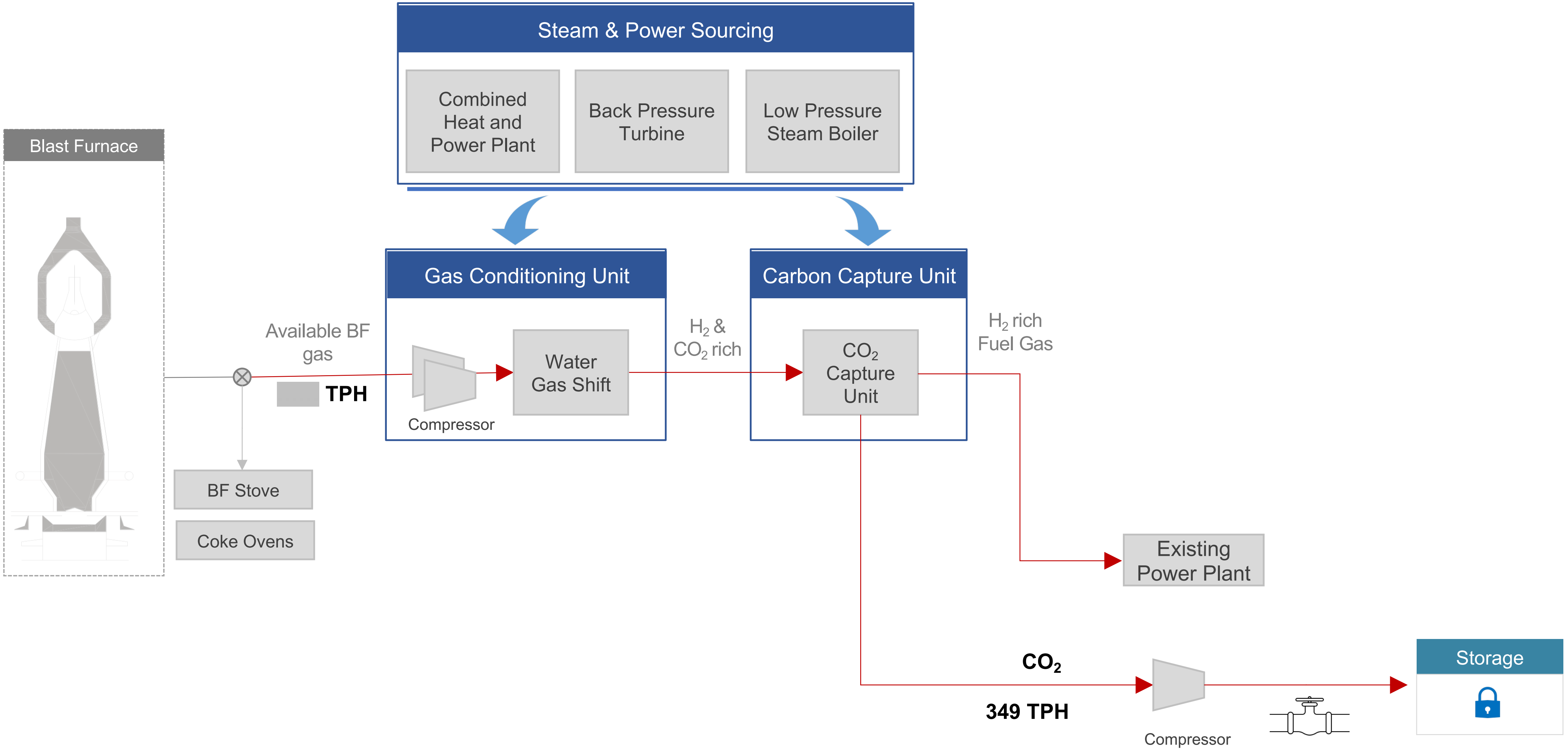
3. **Single point pre-combustion capture** from blast furnace after water gas conditioning **having lower volume and higher CO_2 concentration.**

4. **Flexibility of Design** to control H_2 percentage in the fuel with degree of shift depending on downstream requirement

5. **Optionality to generate 89,000 metric tonne per annum of H_2** from BFG in future by installing suitable gas conditioning at CCU downstream.

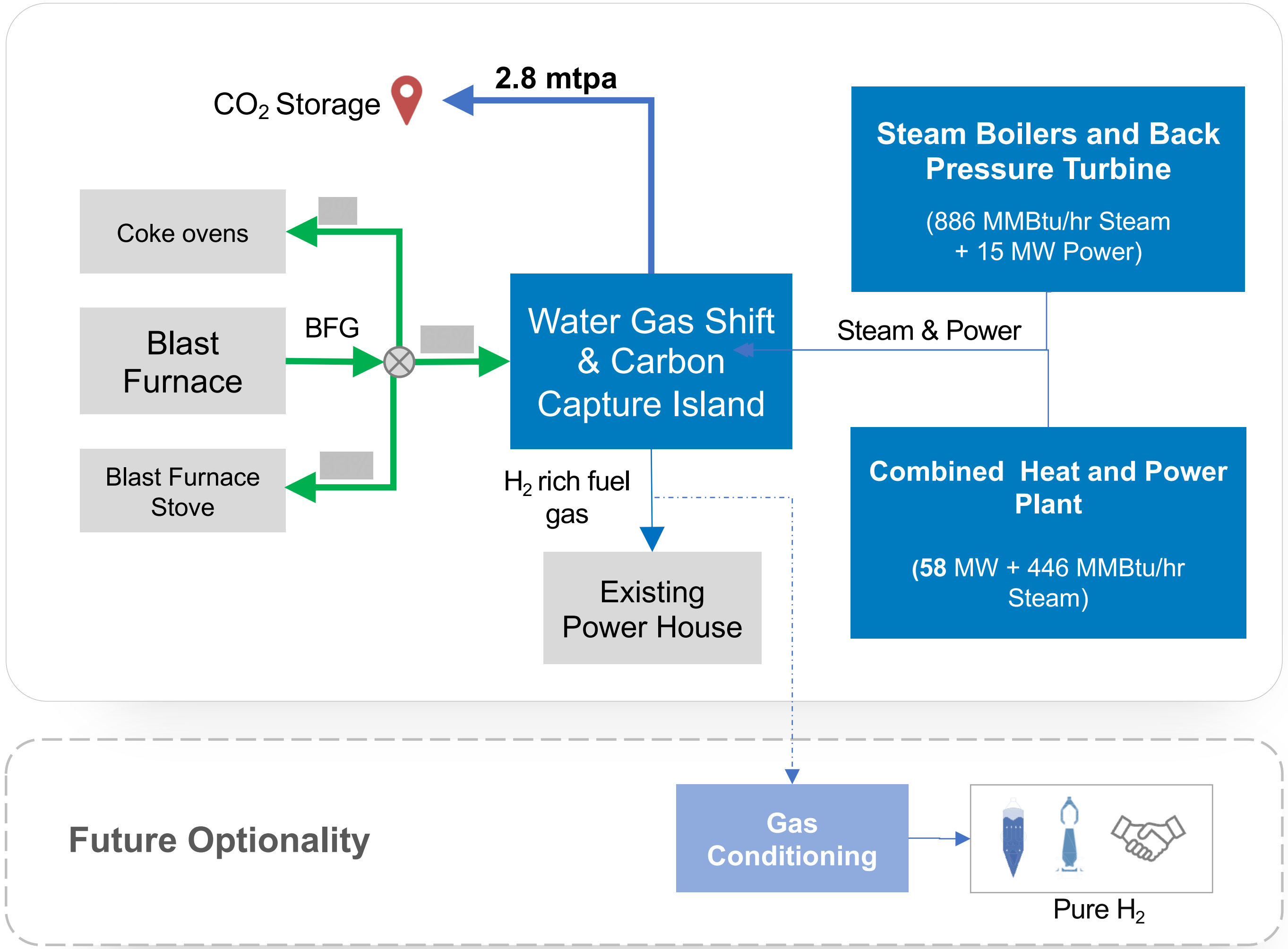
*mtpa : Million metric ton per annum

Block Flow Diagram – Steam and Power Optimized to Ensure to Reduce Operation Cost



Approach to Design of Carbon Capture Island – Optimize Shift and Capture with Steam and Power Network

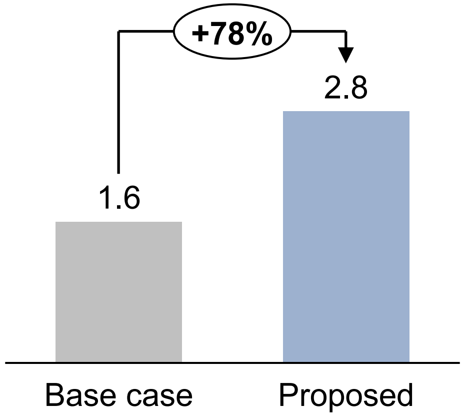
- Maximize carbon capture (2.8 mtpa) with single train CCU
- Increasing CO shift through WGS enables higher CO_2 concentration at CCU; minimizes capex per ton of CO_2 captured



- Cleaner H_2 rich fuel for steam and power generation
- Additional refinement of 89,000 metric tonne per annum hydrogen in future by installing suitable gas conditioning
- Use of hydrogen for steel plant and auxiliary use in future

Design Goal –Increase CO_2 Concentration, Reduce Capture Volume & Cost

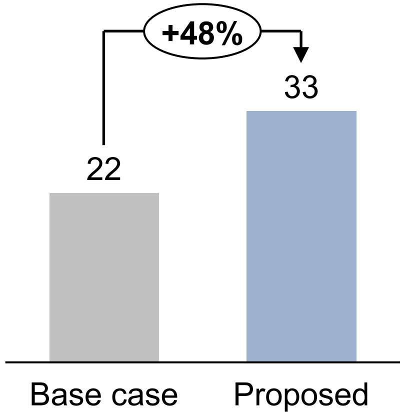
Base case - Carbon capture ONLY from raw BF gas
As designed case - Water gas shift along with carbon capture



CO_2 Capture from BF Gas, MTPA

Single point capture

Higher capture volume from lower volume and higher CO_2 concentration gas.



CO_2 Concentration, %

better capture efficiency + economies of scale

Outline

1 Project Overview

2 Gas Analysis

3 Steam and Power Source

4 Integrated Process Flow

5 WGS and CCU Details

6 CO_2 footprint

7 Cost and Financial

8 Sequestration Update

9 CFD Study of PH Boiler

10 Permit and Constructability

11 Environment and HAZOP

12 Plant Layout

Input and Output Gas Characteristics – 50% Increase in CO_2 Concentration and 150% Increase in H_2 Concentration through Shift

		WGS Input Gas	WGS Output Gas	CCU Output Gas	
Stream description	**Units**	**Blast Furnace Gas**	**Water Gas Shift Output**	**H_2 Rich Gas to Power House**	**Compressed CO_2**
Gas Comp.					
CO	*vol. %*	[redacted]	[redacted]	[redacted]	-
CO_2	*vol. %*	[redacted]	[redacted]	[redacted]	100
H_2	*vol. %*	[redacted]	[redacted]	[redacted]	-
H_2O	*vol. %*	[redacted]	[redacted]	[redacted]	-
N_2	*vol. %*	[redacted]	[redacted]	[redacted]	-
Gas Temp	*°F*	[redacted]	[redacted]	[redacted]	95
Gas Pressure	*psia*	[redacted]	[redacted]	[redacted]	2215
Gas Vol. Flow Rate	*MMSCFD*	[redacted]	[redacted]	[redacted]	160.5
Mass Flow Rate	*Klb/h*	[redacted]	[redacted]	[redacted]	770
Gas CV	*Btu/SCF*	[redacted]	[redacted]	[redacted]	-
Energy Rate	*MMBtu/d*	[redacted]	[redacted]	[redacted]	

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1. Project Overview
2. Gas Analysis
3. **Steam and Power Source**
4. Integrated Process Flow
5. WGS and CCU Details
6. CO_2 footprint
7. Cost and Financial
8. Sequestration Update
9. CFD Study of PH Boiler
10. Permit and Constructability
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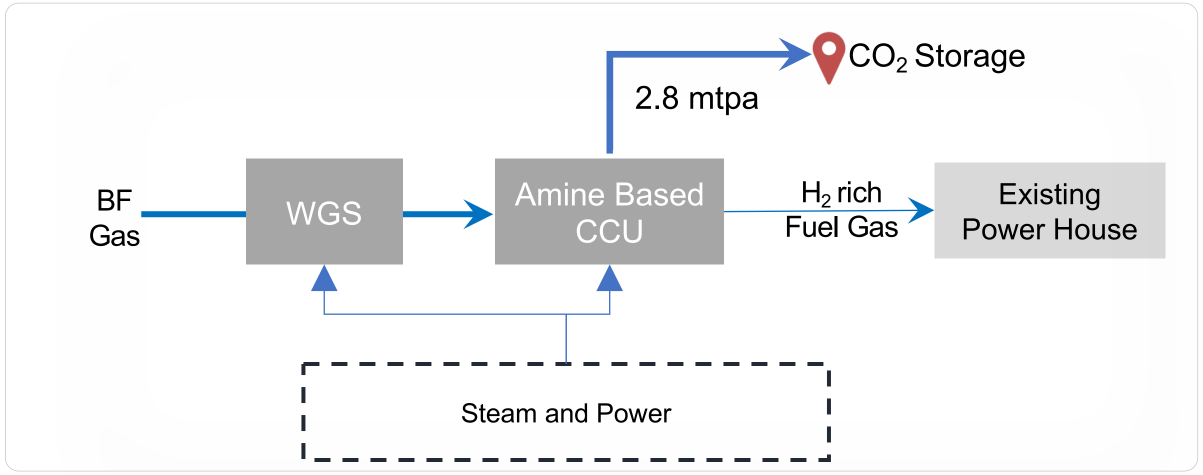
Steam and Power Sourcing Strategy



Opt 1: 15 PSI Steam from Power House

Challenges:

a) [redacted].

b) Insufficient quantity and heat duty for CCU reboiler

c) WGS process needs 60 PSI steam and needs to be generated separately.

d) Additional power generation unit required or power to be imported from grid.

Outcome: Not Considered

Opt 2: Steam from BOF Waste Gas or Biomass Based Boiler

Challenges:

a) Availability of waste gas from BOF is inconsistent and driven by steel production.

b) Sourcing, handling and processing of biomass for boiler is difficult considering the steam quantity.

c) Additional power generation unit required or power to be imported from grid.

Outcome: Not Considered

Opt 3: Steam from Coke Dry Quenching (CDQ) Facilities at Coke Ovens

Challenges:

a) CDQ capacity matched with Coke production.

b) [redacted]

c) [redacted]

d) Additional power and steam generation unit required.

Outcome: Not Considered

Opt 4: Combined Heat and Power (CHP) Unit and LP Boilers

Benefit:

a) Total required electric power can be sourced from CHP and associated back-pressure turbine.

b) Total required steam can be sourced from CHP and LP Boilers.

Outcome: Following facilities considered:

1. **CHP Unit:** To generate 58 MW of electricity and 446 MMBtu/hr steam
2. **BPT unit:** To reduce [redacted] PSIA steam to [redacted] PSIA steam and generate 15 MW of electricity
3. **Steam boilers:** To generate about 886 MMBtu/hr low-pressure steam

Steam and Power Requirement – Efficient Use of High Pressure Steam with Power Optimization

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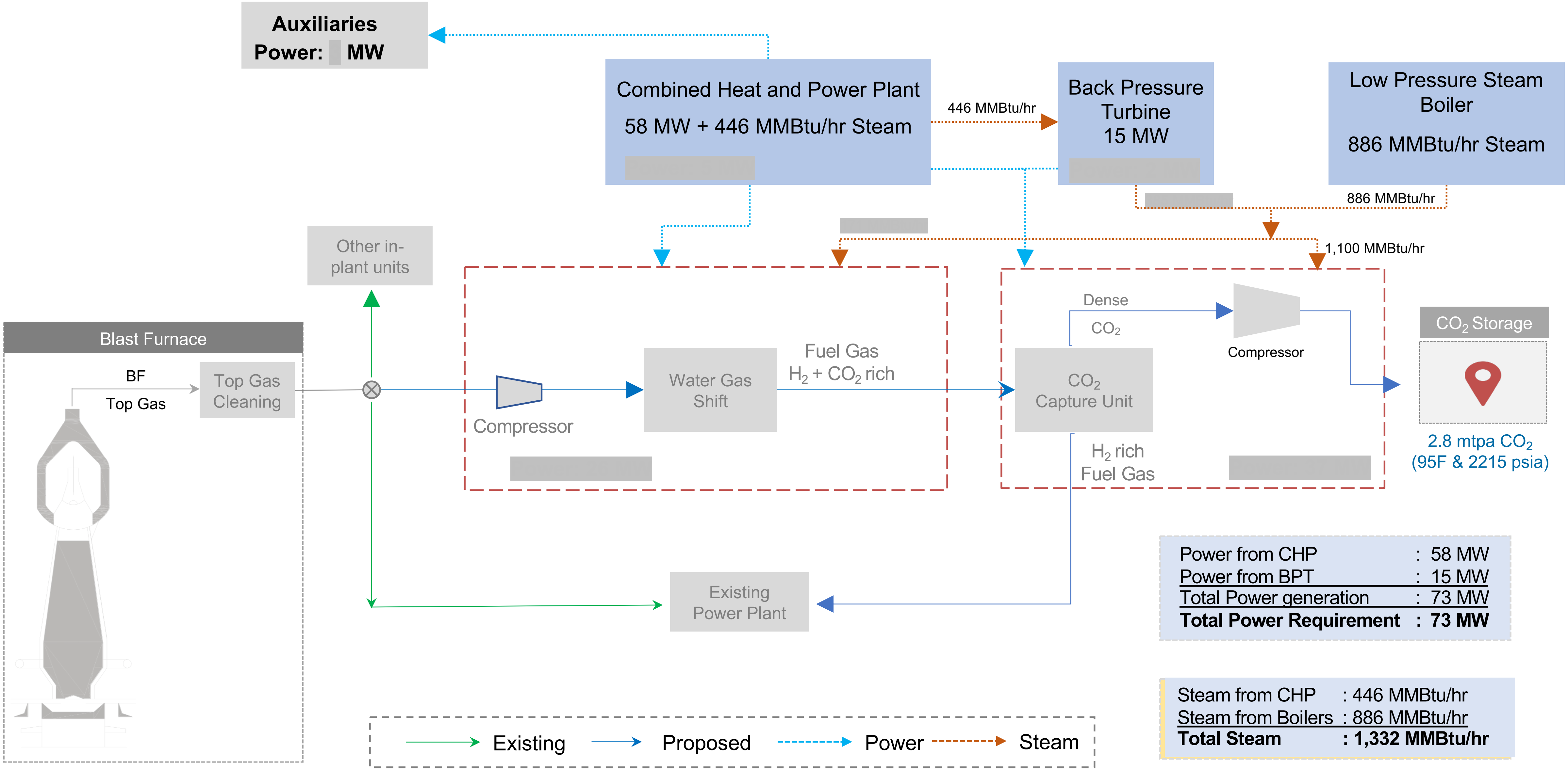

Power from CHP	: 58 MW
Power from BPT	: 15 MW
Total Power generation	: 73 MW
Total Power Requirement	**: 73 MW**

Steam from CHP	: 446 MMBtu/hr
Steam from Boilers	: 886 MMBtu/hr
Total Steam	**: 1,332 MMBtu/hr**

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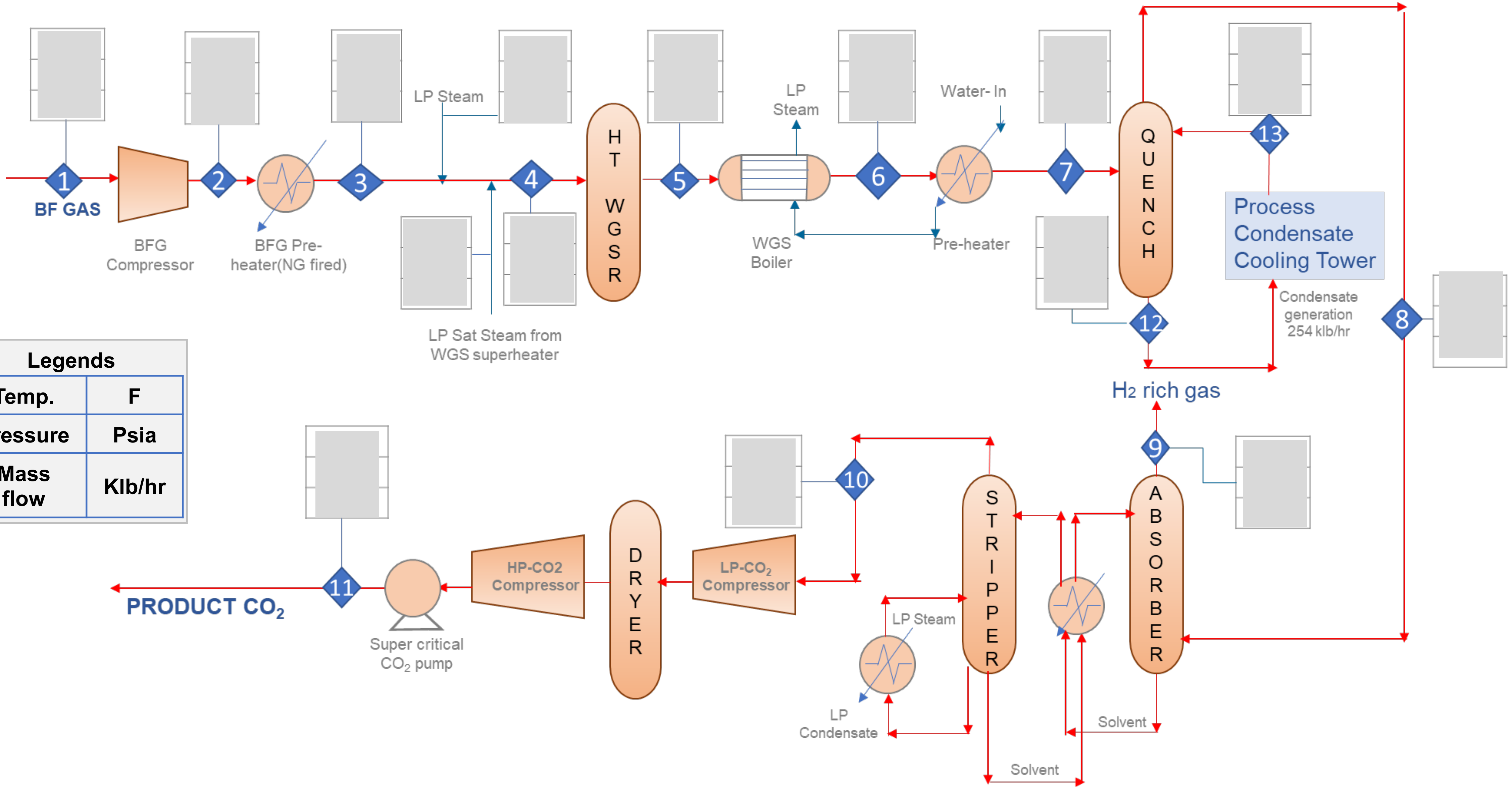
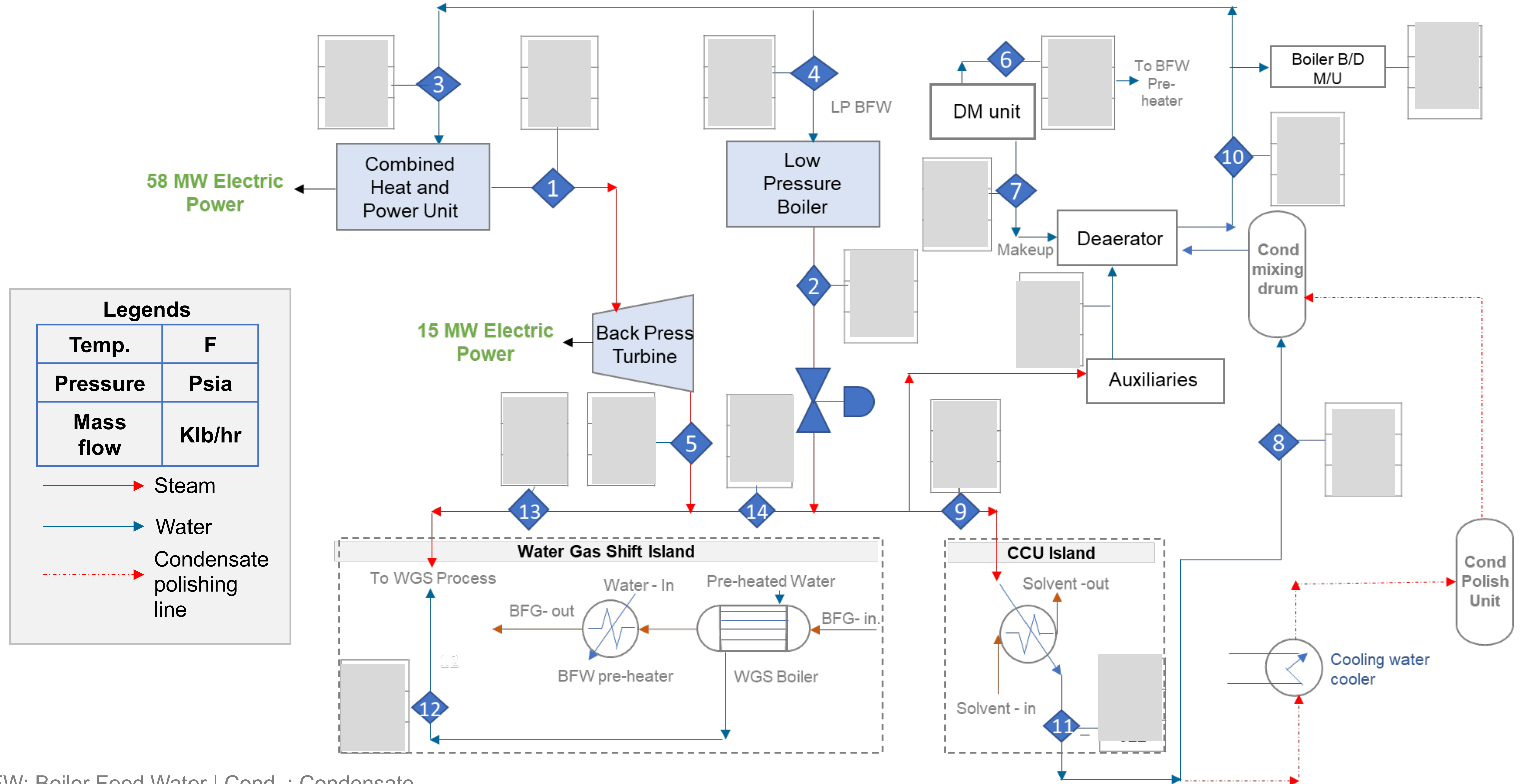
Integrated Process Flow Diagram



Legends

Temp.	F
Pressure	Psia
Mass flow	Klb/hr

Steam and Condensate Balance



BFW: Boiler Feed Water | Cond. : Condensate

Outline

Water Gas Shift Island – Low Pressure Design with Minimal Pressure Drop by Quench Column and NG Pre-Heater

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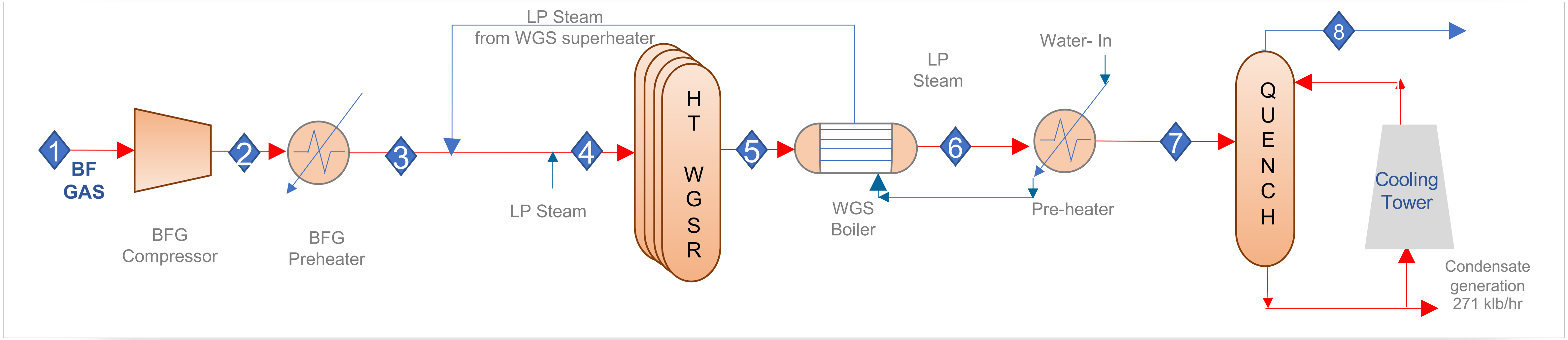
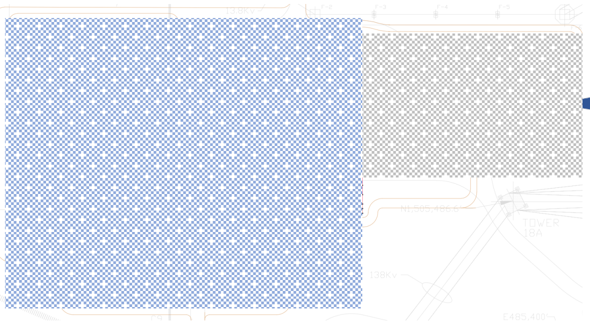
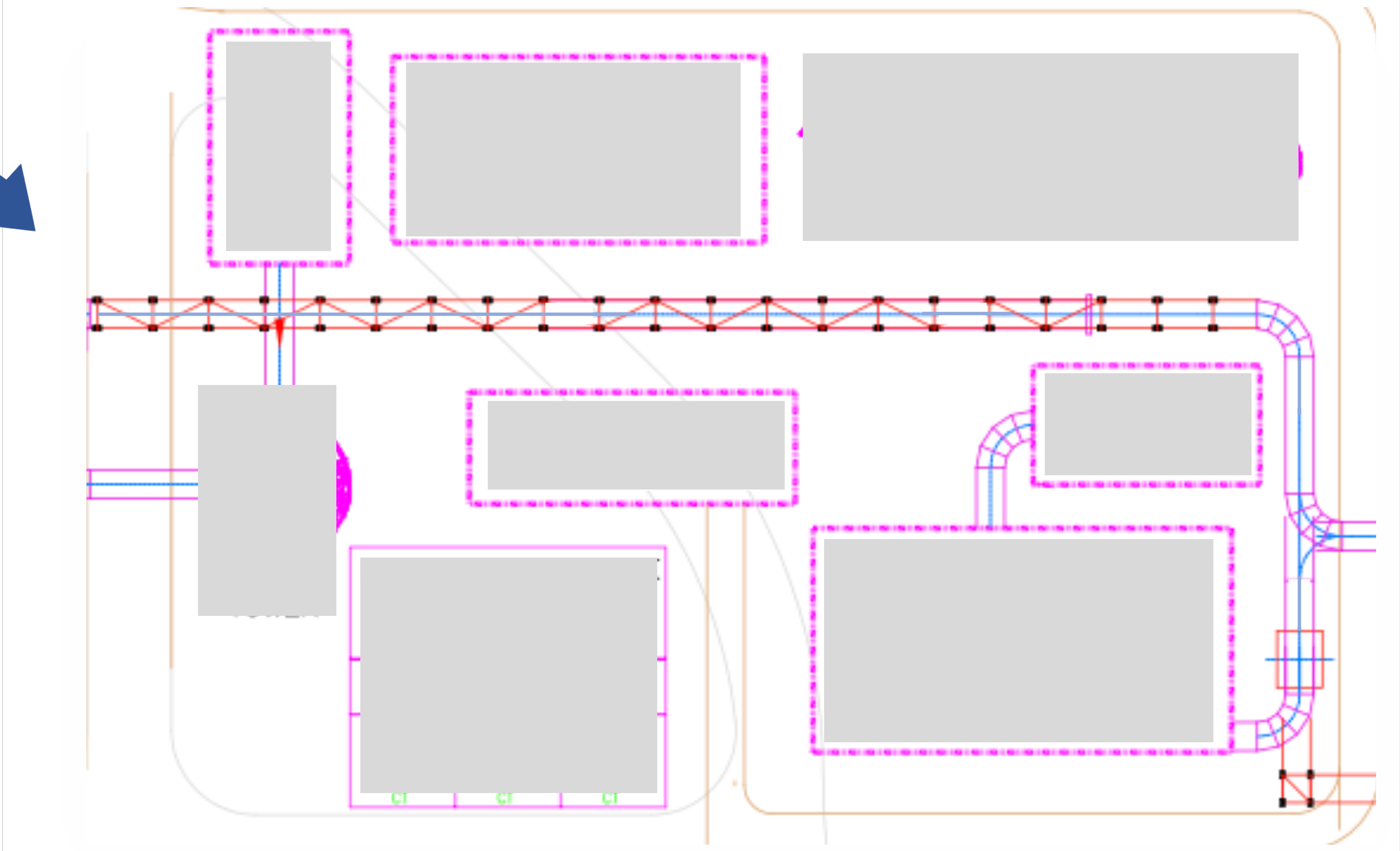


Heat and Mass Balance

Stream description	Units	1	2	3	4	5	6	7	8
CO	*vol. %*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO_2	*vol. %*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
H_2	*vol. %*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
H_2O	*vol. %*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
N_2	*vol. %*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Temp	*°F*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Pressure	*psia*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Vol. Flow Rate	*MMSCFD*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mass Flow Rate	*Klb/h*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Water Gas Shift Island Area Layout and Equipment List





For gas flow, refer to heat and mass balance

Equipment List

1.
2.
3.
4.
5.
6.
7.

Utility Summary of WGS Area

Cooling Water (CW) Utility Summary (100% Water w/ No Glycol in Circuit)					
Utility User	User Description	CW Flowrate	CW Supply Temp	CW Return Temp	CW Duty
		GPM	*°F*	*°F*	*MM Btu/hr*

Steam Utility Summary						
Utility User	User Description	Steam Flowrate	Steam/Cond Pressure	Steam/Cond Temp	Total Enthalpy	Steam Duty
		lb/hr	*psia*	*°F*	*Btu/lb*	*MM Btu/hr*

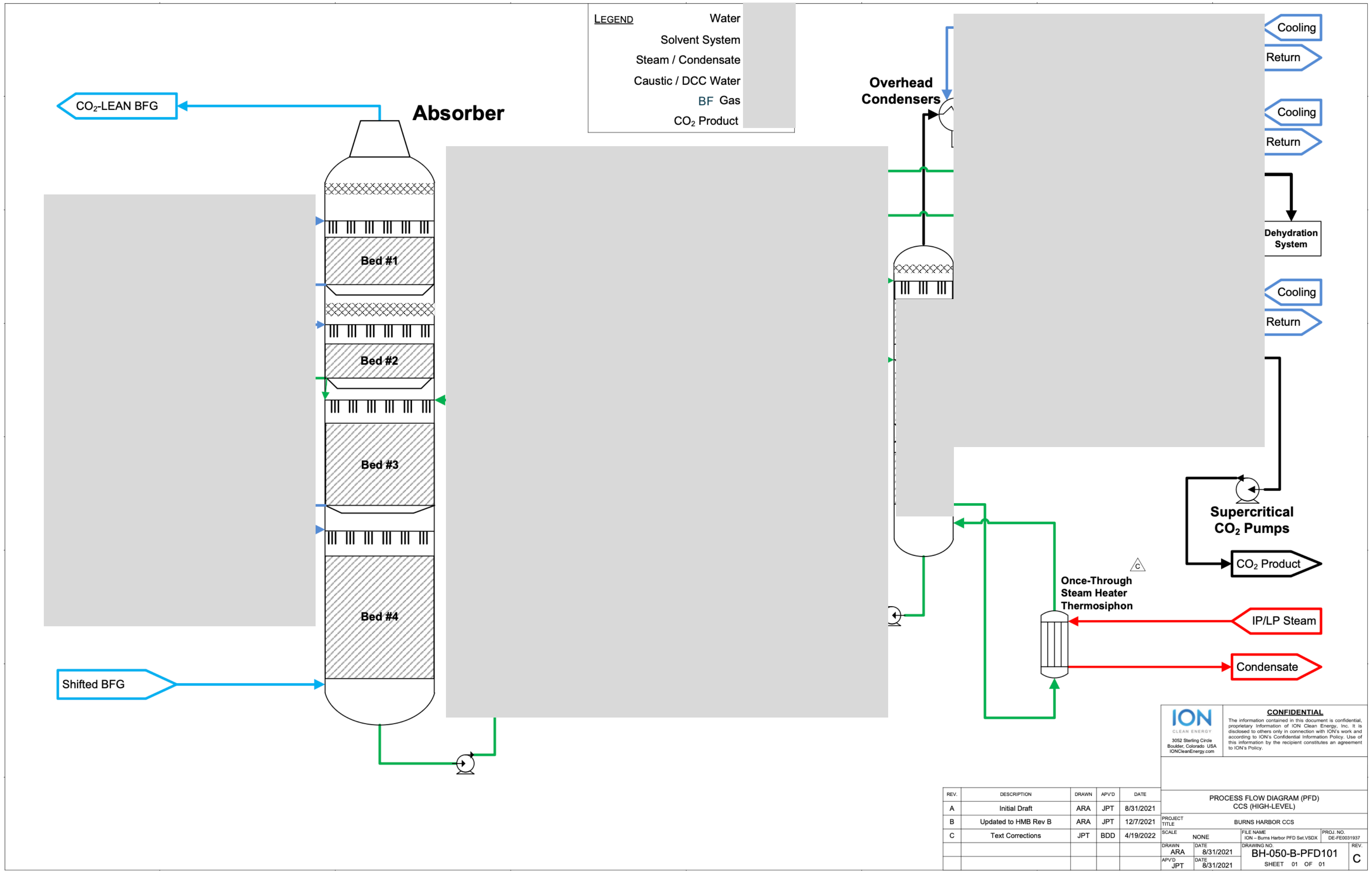
Natural Gas Consumers (30 PSIG, min, req'd)			
Utility User	User Description	Total Consumed Klb/hr	Total MM Btu/hr

Nitrogen Gas Consumers (80 PSIG, min, req'd)		
Utility User	User Description	Consumed SCFH
	Total Consumed SCFH	2,000

Major Power Consumers (> 300 HP & Consistent)					
Utility User	User Description	Total Consumed kW		Total Conn'd HP (est)	
	Total	26	MW	39,000	HP

Wastewater Summary	
Total Wastewater	250

Carbon Capture Island – Process Flow Diagram



Carbon Capture Island – Heat and materials Balance (1/2)

Stream Number	101	101	103	201	202	203	204	205	206	207	208	301	302	303	304	305	401
Location	DCC	ABS	UWW	LWW	LWW	LWW	UWW	UWW	UWW	UWW	UWW	ABS	ABS	LRXC	CRB	LRXC	StmHeat
Description																	
Mass Flow (lb/hr)																	
H_2O†																	
CO_2																	
ION Solvent																	
N_2																	
H_2																	
CO																	
Total Flow (lb/hr)																	
Temperature (F)																	
Pressure (psia)																	
Vapor Fraction (%)																	
Density (lb/cuft)																	
Gas Flow (ACFM)																	
Liq Flow (GPM)																	

Stream Number
Location
Description
Mass Flow (lb/hr)
H_2O†
CO_2
ION Solvent
N_2
H_2
CO
Total Flow (lb/hr)
Temperature (F)
Pressure (psia)
Vapor Fraction (%)
Density (lb/cuft)
Gas Flow (ACFM)
Liq Flow (GPM)

Carbon Capture Island – Heat and materials Balance (2/2)

Stream Number	512	513	701	702	703	704	705	706	707	708	709
Location	HPCond	sCO2Pump	Intercooler	Intercooler	LPInter	Stripper	LPInter	HPInter	LPInter	HPInter	Stripper
Description											
Mass Flow (lb/hr)											
H2O†											
CO2											
ION Solvent											
N2											
H2											
CO											
Total Flow (lb/hr)											
Temperature (F)											
Pressure (psia)											
Vapor Fraction (%)											
Density (lb/cuft)											
Gas Flow (ACFM)											
Liq Flow (GPM)											

† Water Mass Flow is relative to the base water content in the solvent and will fluctuate as water content increases and decreases throughout the process.

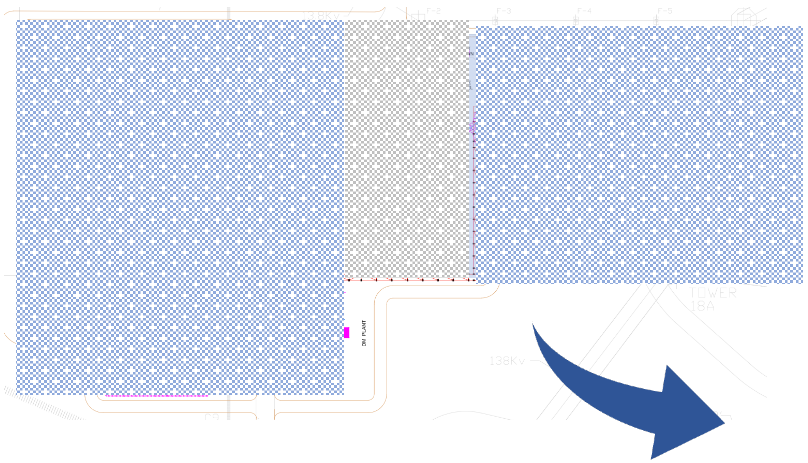
Carbon Capture Island - Utility Summary

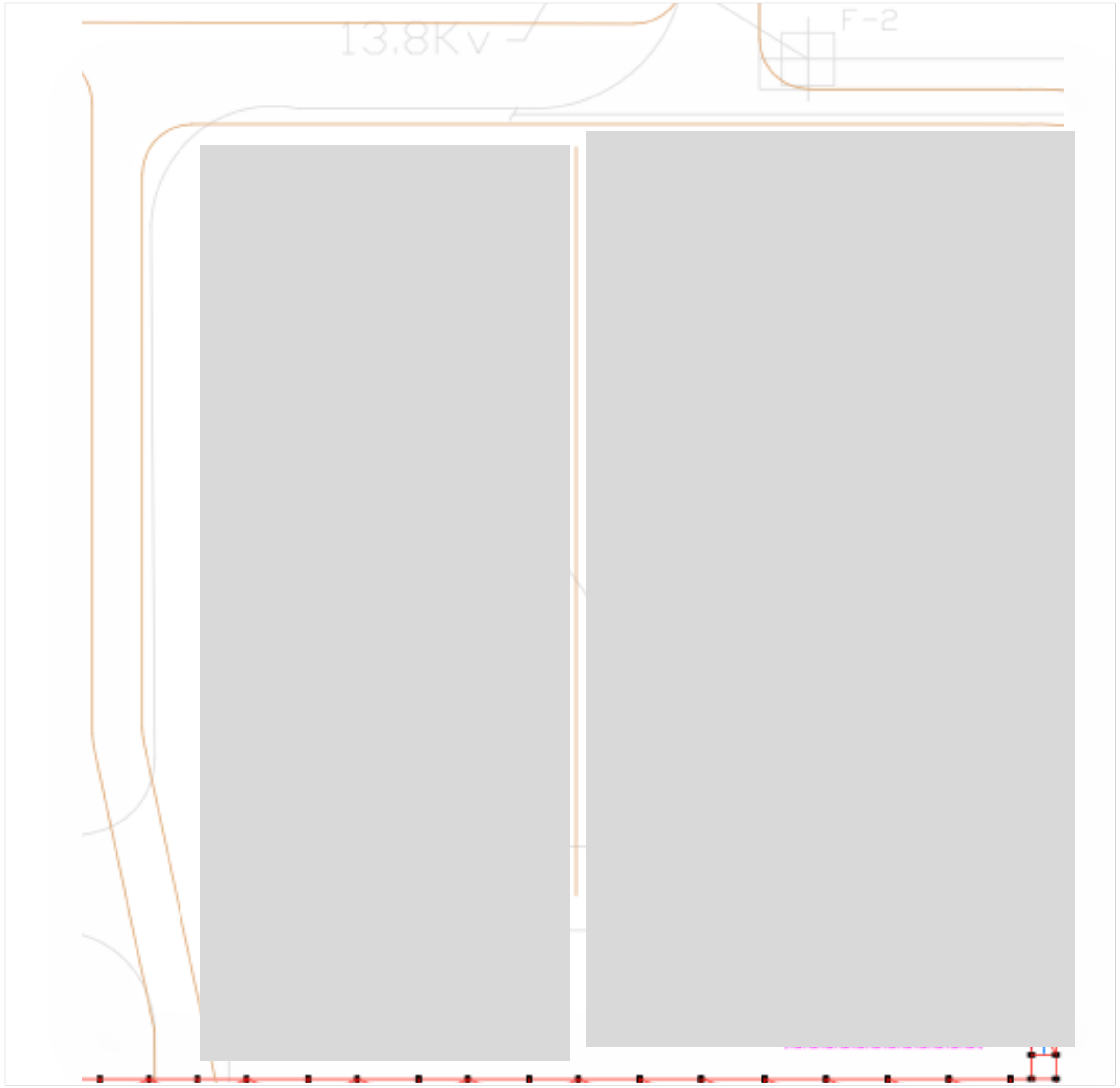
Cooling Water (CW) Utility Summary (100% Water w/ No Glycol in Circuit)					
Utility User	User Description	CW Flowrate	CW Supply Temp	CW Return Temp	CW Duty
		GPM	*°F*	*°F*	*MM Btu/hr*

Steam Utility Summary						
Utility User	User Description	Steam Flowrate	Steam/Cond Pressure	Steam/Cond Temp	Total Enthalpy	Steam Duty

Major Power Consumers (> 300 HP & Consistent)

Carbon Capture Island – Site Plan and Equipment List





For gas flow, refer to heat and mass balance

Equipment List

1. Absorber – 1 each
2. Stripper – 1 each
3. Lean-Rich Heat Exchanger– 4 each
4. Absorber cooler – 2 each
5. Stripper steam heater – 2 each
6. CO_2 compressor – 1 each
7. CO_2 cooler – 1 each
8. CO_2 condenser – 2 each
9. Supercritical CO_2 pump – 2 each

Outline

CO_2 Footprint - 2.8 mtpa CO_2 Capture with 0.72 mtpa Scope 1 CO_2 Emissions resulting in 2.08 mtpa of Net CO_2 Abatement

	Steam	Power	Natural Gas	Make-up Water	CO_2 Capture	CO_2 Emission
BFG Pre-heater						
BFG Compression						
Water Gas Shift						
CCU						
Boilers + Deaerator + Misc. Pump						
BPT						
Total						
Captive Generation	1,332 MMBtu/hr	73 MW	-	-		
Net Import	-	-	1,691 MMBtu/hr	3,120 GPM	Net CO_2 abated inside CCU project BL	**2.08 mtpa**
Existing PH (Equv. NG compensating energy shortfall)	-	-			-	
					Net CO_2 abated incl. addnl. emission in PH	**2.01 mtpa**

Outline

Key Assumptions

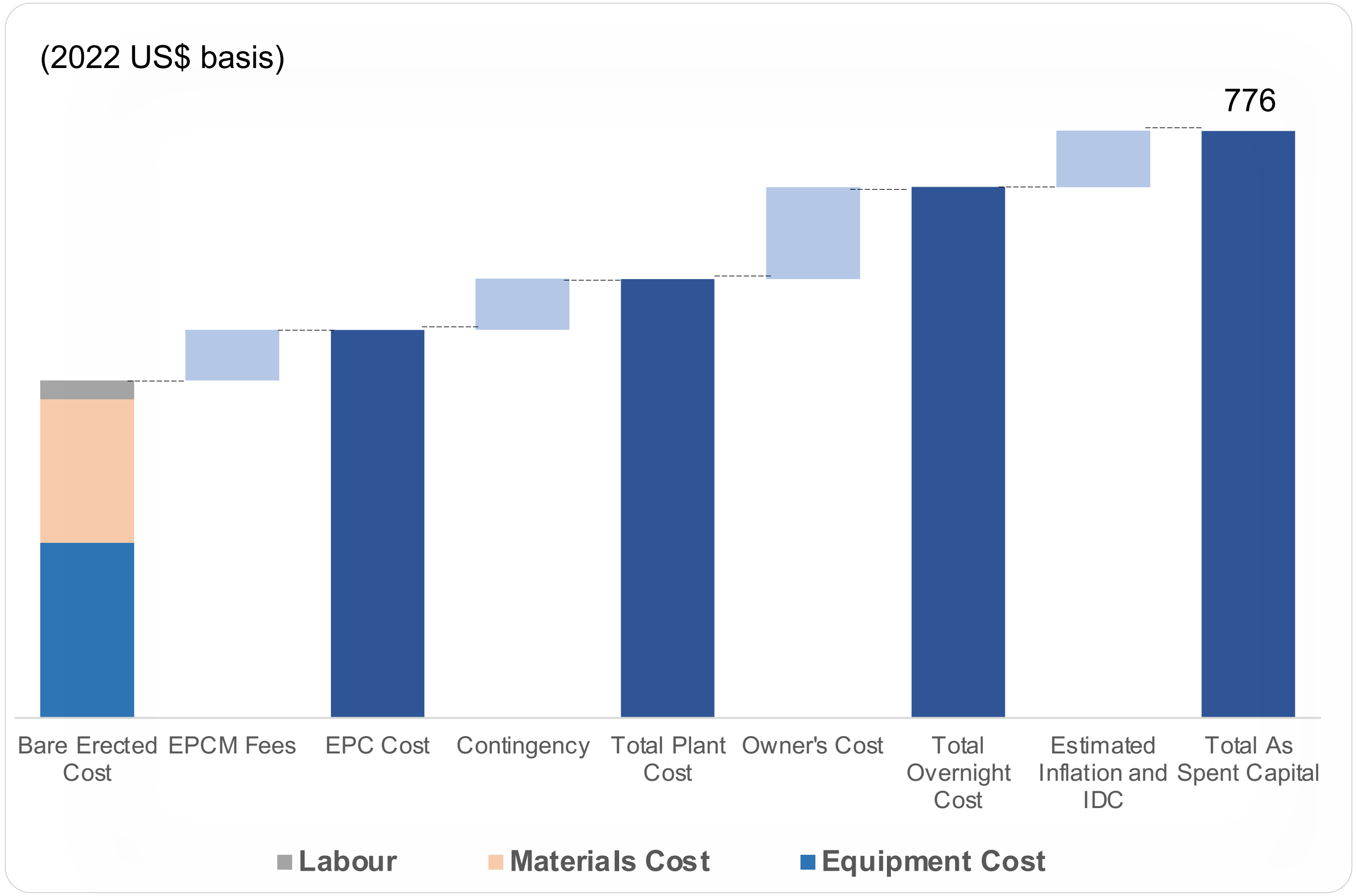
- Capital cost and operating cost estimated based on **"Quality Guidelines For Energy System Studies" published by NETL and AACE 16R-90 (Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries),** wherever applicable
- CO_2 Transportation and storage cost has been considered 10 $ per Tonne of CO_2 as suggested by DoE in **"Appendix C - Basis for Techno-Economic Analysis"**
- Equipment cost has been estimated based on budgetary quote from US based suppliers.
- No discount (negotiation margin) considered on budgetary offer

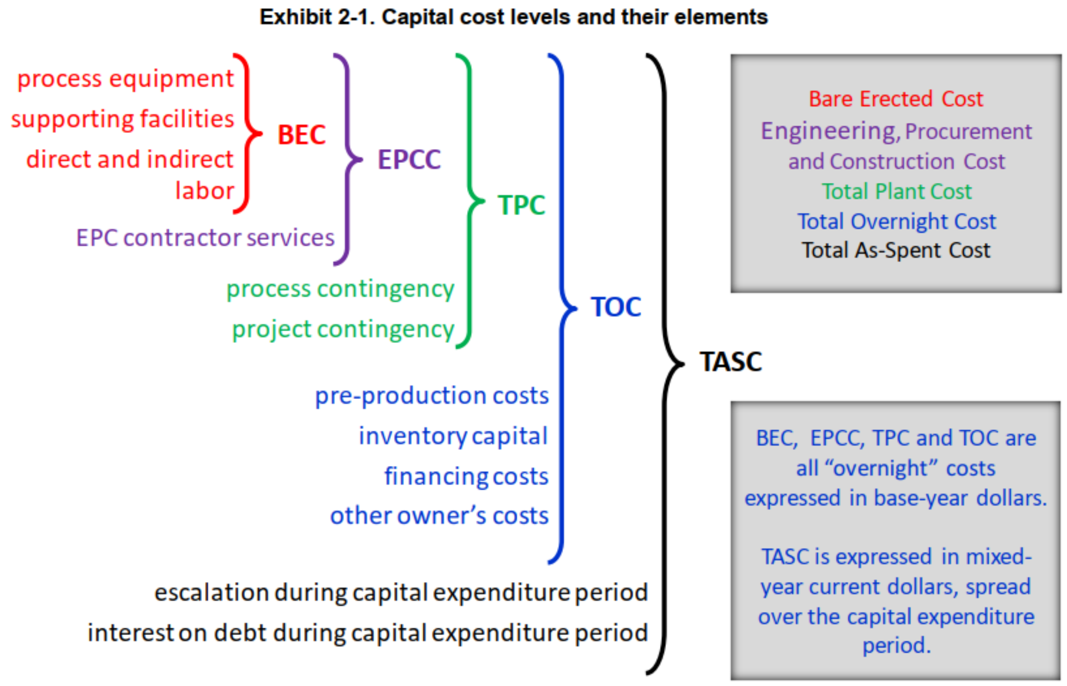
<u>Operation Cost assumption</u>

- Long term natural gas cost @ 5 $/MMBtu
- O&M cost has been calculated based on an annual capture volume of 2.8 mtpa with availability for 8,000 hours
- Overhead cost like payroll, admin & corporate considered as zero as existing operation can take care of additional 20 persons for operation
- BF gas & H_2RF cost considered at Natural gas cost

Sensitivity analysis has been made for variation of natural gas, capital cost, leverage ratio, interest, tax, return on equity, and capacity utilization scenarios

Capital Cost Estimate in MM$





Note:

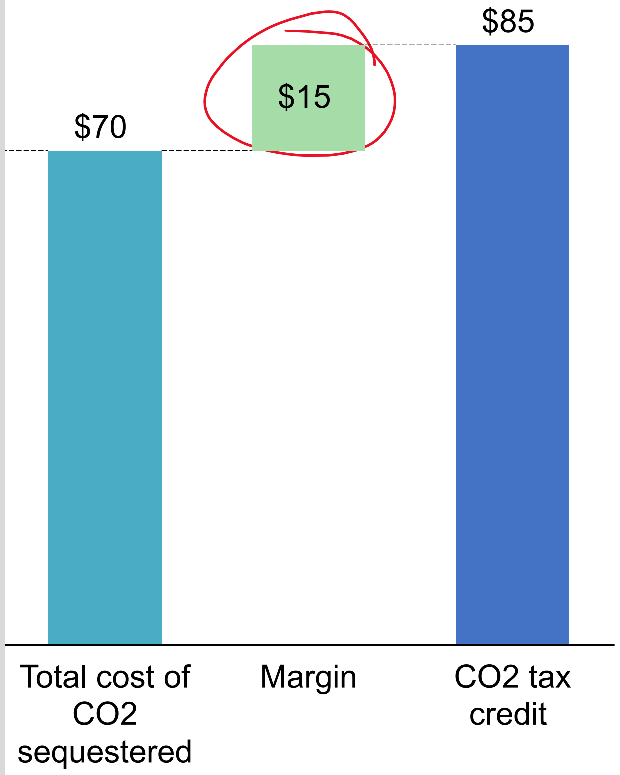
1. EPCM fees have been considered at 15%
2. 10% process contingency has been considered for the carbon capture unit. Project contingency is calculated considering 10% of EPC cost plus process contingency.
3. Escalation cost and interest during construction have been estimated considering three years construction period with 1-year of pre-engineering activity. T-oY escalation of 3% is considered throughout the construction period. And Interest during construction has been calculated on the debt part only.

Annual Operating Cost Estimate

Particulars	Annual Consumptions	Unit rate	Subtotal in Thou US$	Total in Thou US$	US$/Tonne of CO_2
	1	2	3=1x2	4	
Fuel					
Raw Material BF Gas					
By-products H2RF					
Fuel for Steam & Power production					
Fuel for Process					
Total Fuel $					
Utilities and Consumables					
Nitrogen and Colling water					
Catalyst & Chemical					
Total Utilities and Consumables $					
Labor Cost					
Labor, Direct					
Labor, Indirect (75% of direct labor)					
Total Annual Labor $					
Other Costs					
Maintenance cost (3% of total plant cost)					
Property tax and insurance (2% of total plant cost)					
Total Other Costs $					
Total Annual Operating Cost $				**$ 115,049**	**$ 41.2**

Cost of Capture and Margin, in US$/Tonne of CO_2

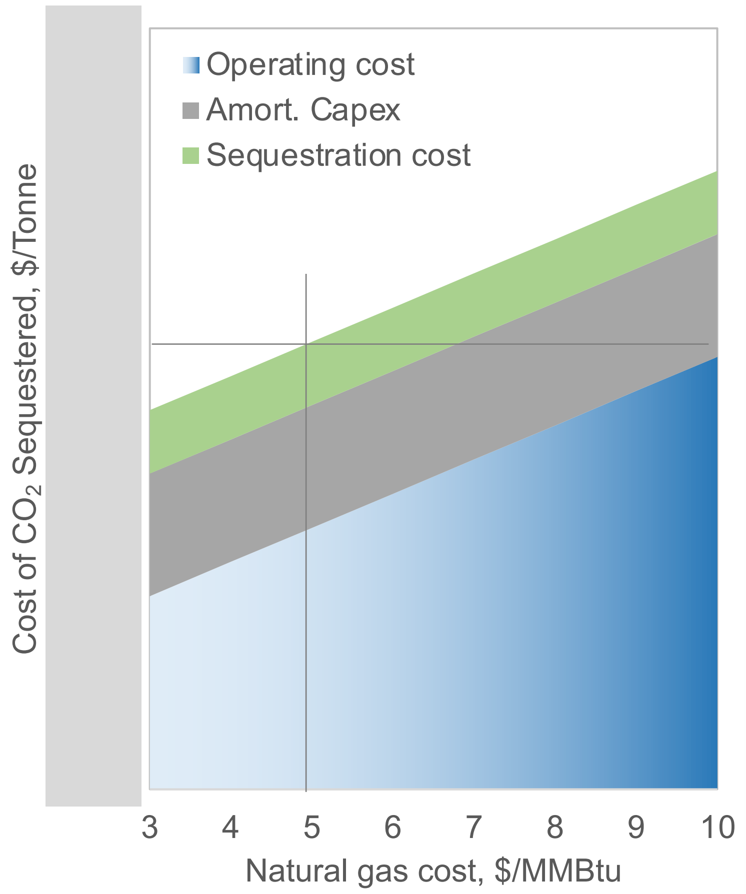
(2022 Constant US$ basis)



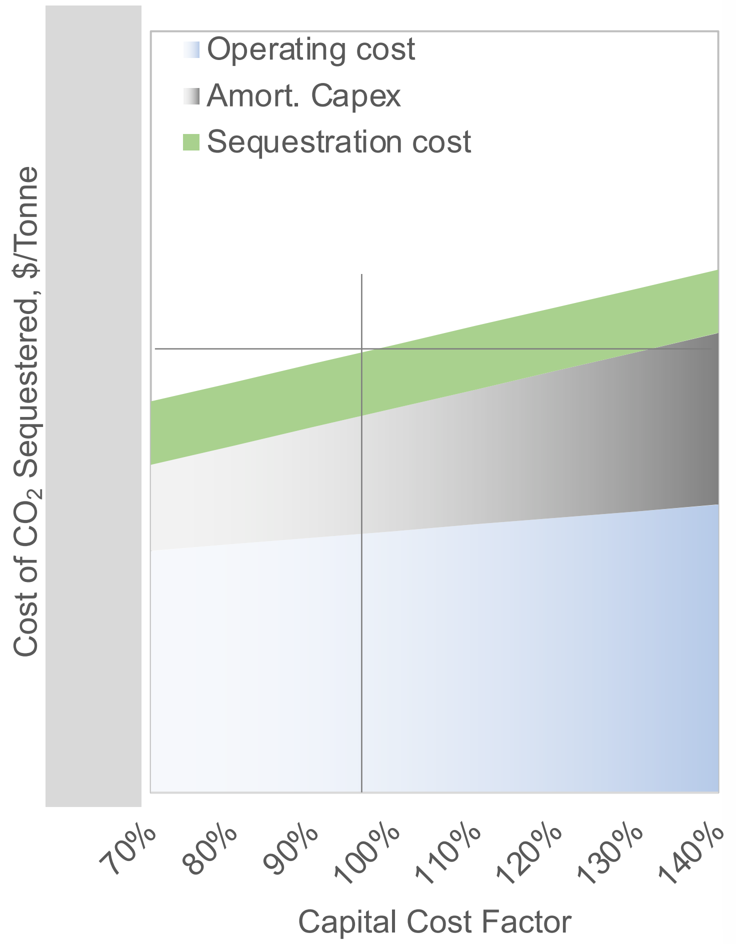
* CO_2 Transportation and storage cost has been considered 10 $ per Tonne of CO_2 as suggested by DoE in **“Appendix C - Basis for Techno-Economic Analysis”**

Sensitivity Analysis - Cost of CO_2 Sequestered (US$/Tonne)

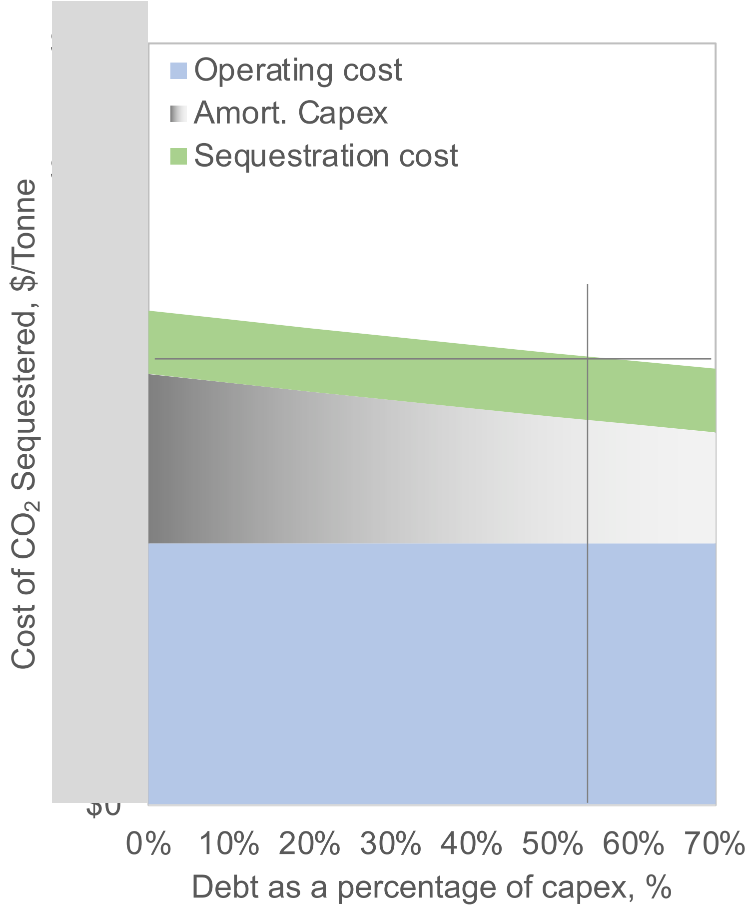
Sensitivity on Natural Gas Cost



Sensitivity on Capital Cost

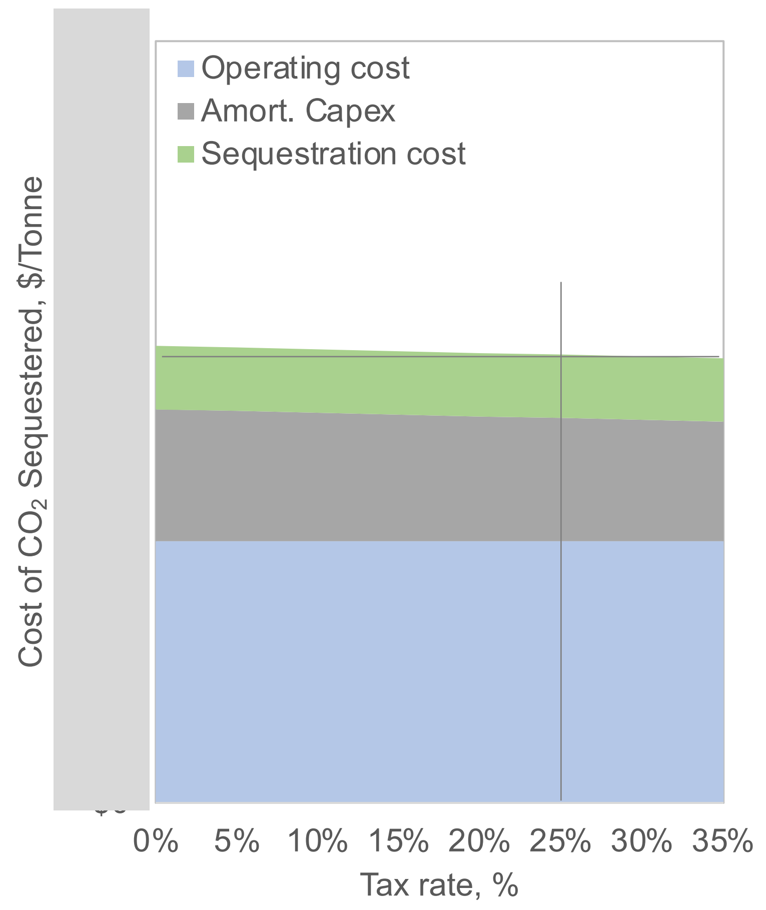


Sensitivity on Leverage Ratio

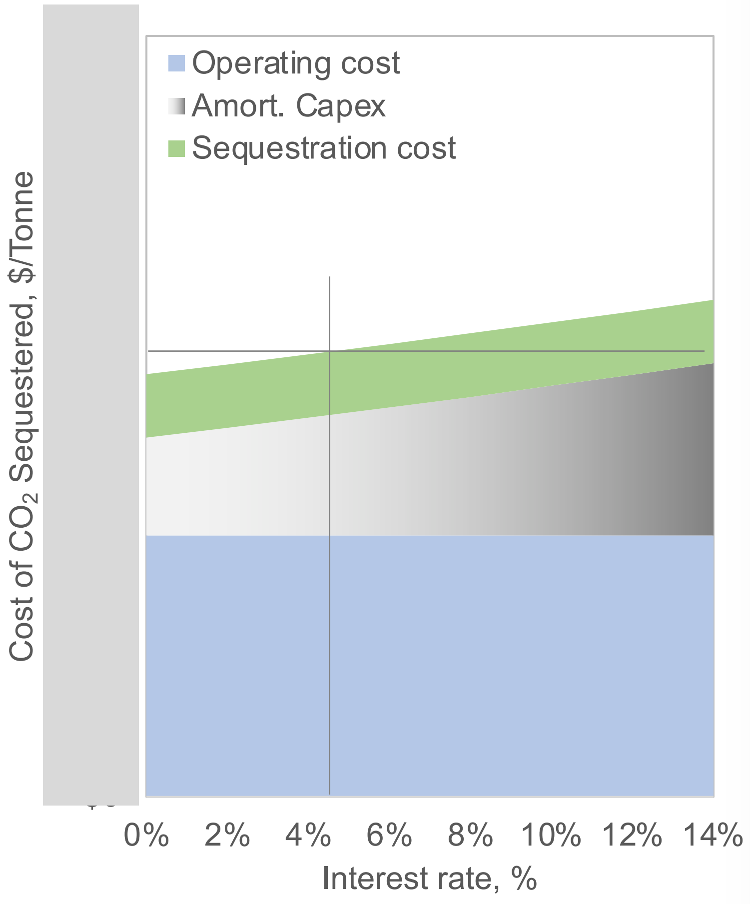


Sensitivity Analysis - Cost of CO_2 Sequestered (US$/Tonne)

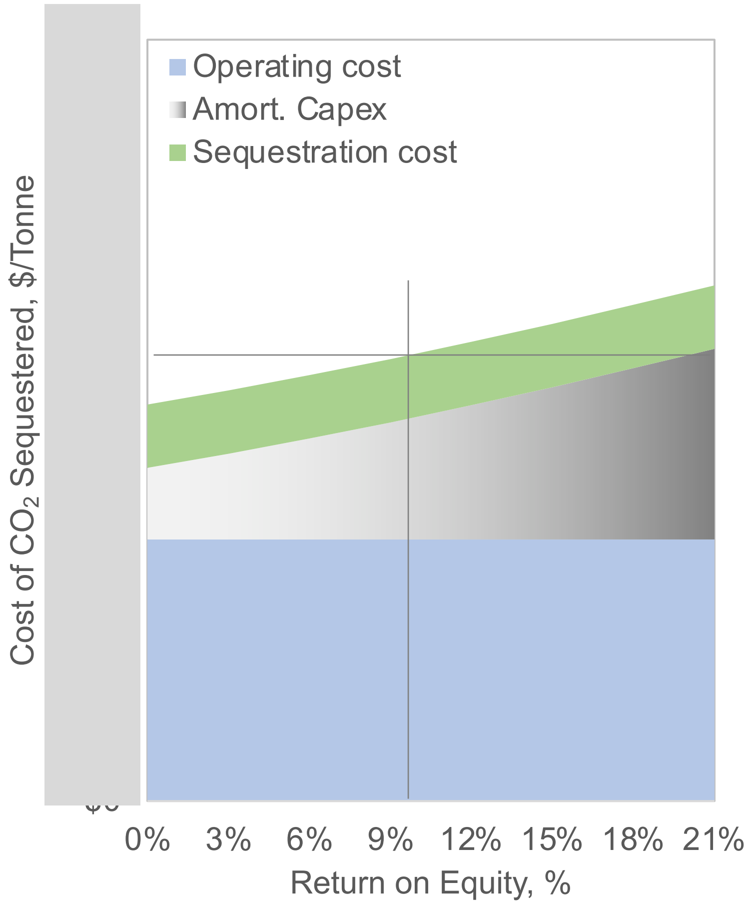
Sensitivity on Tax Rate



Sensitivity on Interest Rate

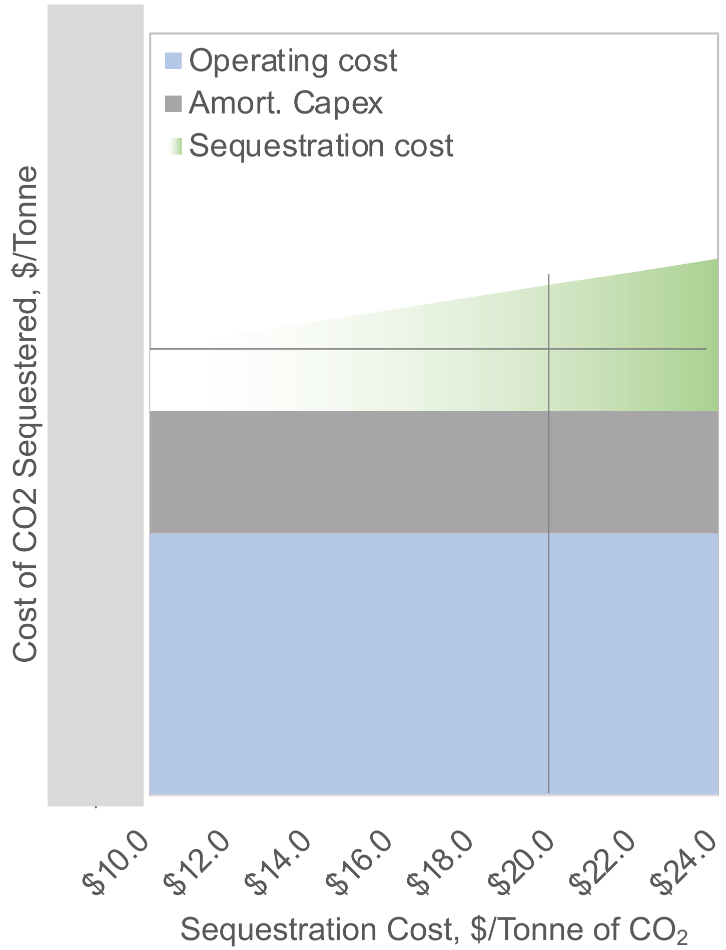


Sensitivity on Return on Equity

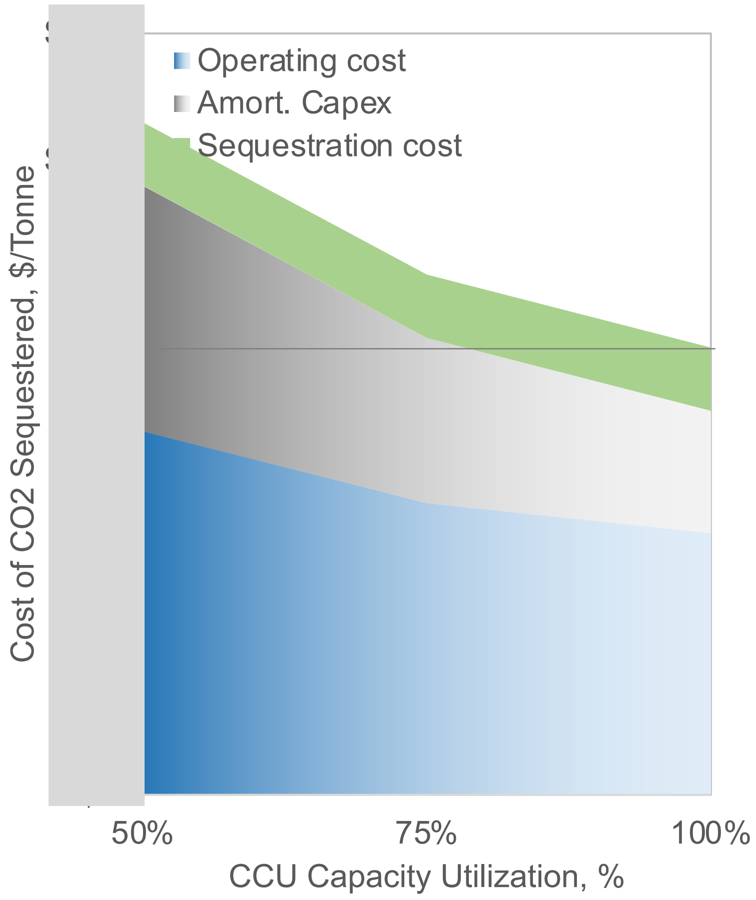


Sensitivity Analysis - Cost of CO_2 Sequestered (US$/Tonne)

Sensitivity on Sequestration Cost



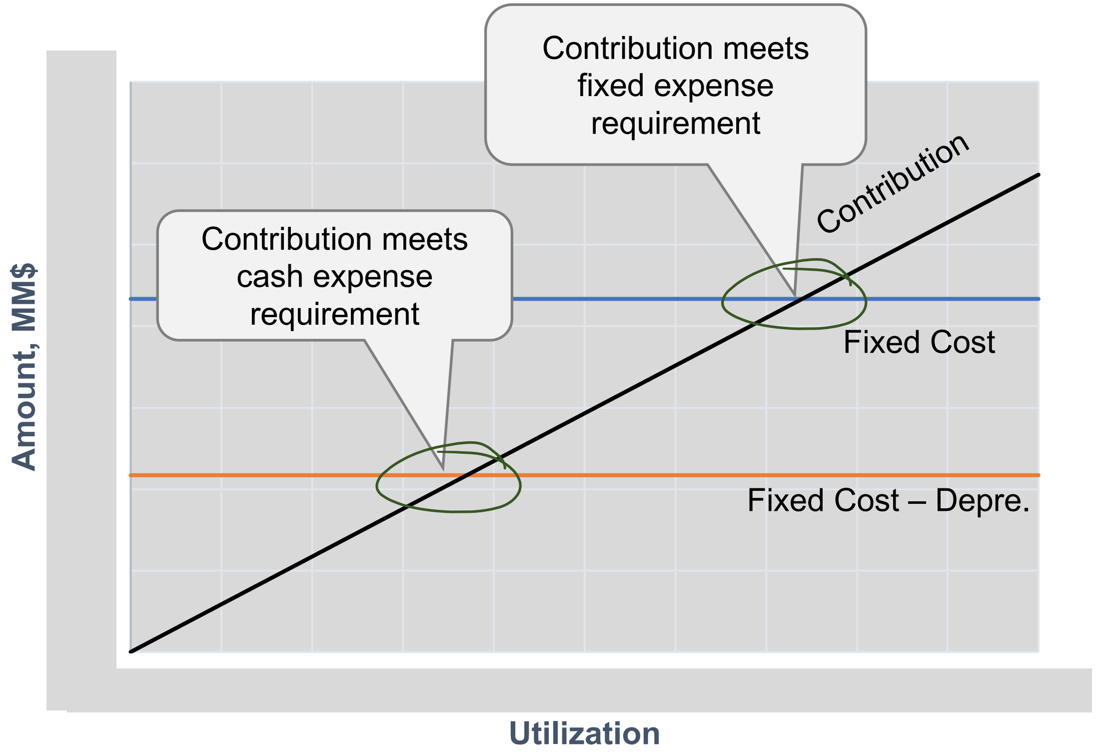
Sensitivity on CCU Capacity Factor/Utilization



Breakeven Analysis

	Particulars	Amount in MM$
		At 1st Stabilized year
A	**Variable Cost**	
	Input Feed Less Byproduct	
	Consumables	
	Utilities	
	Maintenance Cost	
	Sequestration Cost	
	Total Variable Cost (A)	
B	**Fixed Cost**	
	Direct Labor	
	Indirect Labor	
	Other costs (Maint., Ins. & Taxes)	
	Depreciation	
	Interest cost	
	Total Fixed Cost	
C	**Total Tax Credit**	
D	Contribution (C-A)	
	Breakeven Capacity (B/D)	
	Cash Breakeven (B- Depreciation)/D	

Illustration



Levelized Cost of Capture, in US$/Tonne of CO_2

Levelized Cost of Capture per Tonne of CO_2 = Levelized Capital Cost per Tonne of CO_2 + Levelized Operating Cost per Tonne of CO_2 + Levelized Sequestration Cost per Tonne of CO_2

To calculate levelized cost, annual cost incurred over the life and annual CO_2 volume have been discounted at "After Tax Weighted Average Cost of Capital".

Capital Cost Details

Facilities	Equipment cost	Material cost	Labor cost	Bare Erected Cost	EPCM Fees	EPC Cost	Contingency	Total Plant Cost	Owner's Cost	Total Overnight cost
	1	2	3	4=1+2+3	5	6=4+5	7	8=6+7	9	9=7+8
BF Gas treatment (Compression & Water Gas shift).										
Carbon Capture Island incl. CO_2 Compression										
Power & Steam System (GT, ST, BPT)										
BOP Facilities (DM Plant, Yard electrics, Yard water)										
Total										
Preproduction cost										
Inventory capital										
Land										
Financing cost										
Other Owner's cost										
Total Owner's cost										
Total Overnight cost										**701.6**

Total As Spend Capital (TASC) cost is estimated at around 776 MM$ which includes interest and escalation of cost during construction period.

Outline

DASTUR

Mt. Simon is a Preferred Formation for CO_2 Sequestration

1

High-quality injection zone: Mt. Simon is a well-known formation across the Illinois basin with deep well injection permits at various places.

2

Viable option: The only viable large-volume CO_2 storage zone identified in Porter County is the Cambrian age Mt. Simon formation. Storage in shallower formations are not high enough pore pressure at this site.

3

Existing class VI well permits: Mt. Simon has existing class VI well permits at:

- Archer Daniels Midland site in Decatur, IL (under injection since 2014),
- Future Gen site in Mattoon, IL (permitted but never injected).

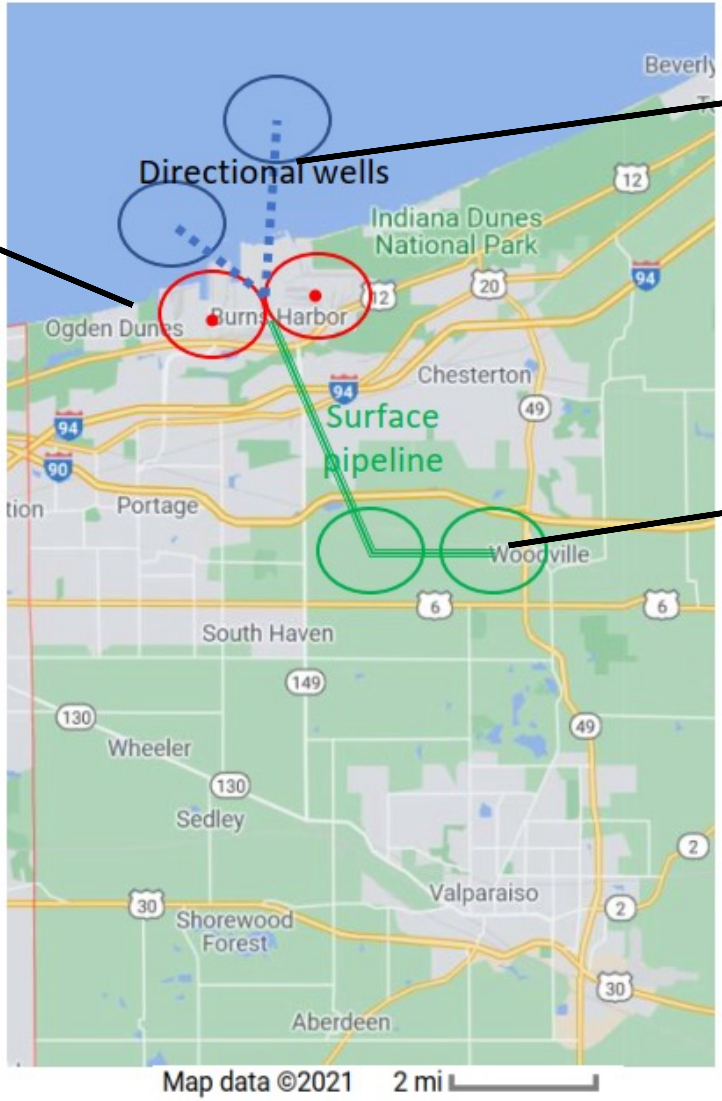
4

Class I well injection experience at this site: This can be very useful in the development of class VI well permits.

Mt. Simon Formation in Porter County are Suitable for CO_2 Storage

Option 1

Injection with CO_2 plume placed beneath the plant site



Option 2

Deviated injection well from the plant site with plume placed beneath Lake Michigan

Option 3

Pipeline south to large land tract south of the developed areas

Storage Site Options

1 CO_2 plume beneath the plant site

- Plant site area: 3 km north-south; 5 km east-west.
- 2 injection wells might be accommodated but risk that plumes may migrate off plant site.
- Storing at the plant site can be problematic because of possible pressure interference with existing class I wells:
  - Reduced injection rates
  - Increased AOR
  - Increased magnitude of pressure
  - Possible increased risk of leakage

2 CO_2 plume beneath the Lake Michigan

- Deviated wells with subsurface perforated injection points.
- North of the plant beneath Lake Michigan.
- Technically feasible; high drilling costs
- Reduces environmental impact.
- Offshore CO_2 sequestration is a common practice:
  - Europe: Sleipner and Snøhvit projects, Northern lights project
  - Louisiana: Air Products Lake Maurepas project
- CO_2 injection beneath state-owned lakes under consideration in other states.

3 Large land tracts south of developed areas

- Can be explored if:
  - Interference with class I wells or
  - Land availability is an issue at the plant site.
- Acquisition of leasing or easement rights for storage
- Higher pipeline construction costs incurred.
- Access to AOR for monitoring is needed.
- Public acceptance and environmental justice issues to be considered.

Outline

Methodology used for CFD Investigation

Objective

1 Effect of H_2 rich gas in Boiler

a. Temperature & velocity profile
b. NOx generation
c. Flashback analysis

2 Acceptable maximum H_2 for combustion

Procedure

- Boiler/Burner design and geometry
- Flow parameters (composition, pressure & temperature, air factor)
- Measured data

CFD model building

Validation of model with operating data

Simulation of Options

Base Cases

1. Min BFG
2. Max BFG

H_2 Rich Gas Fuel (H2RF) cases

1. Min H2RF (31% H_2)
2. Max H2RF (31% H_2)
3. Min H2RF (36% H_2)
4. Max H2RF (36% H_2)

Note

1. Min & Max are the lowest and highest of the BFG or H2RF flow rate range fed to the boilers
2. COG and NG flow rates adjusted to yield a total heat input rate of 550 MMBTU/h

CFD Analysis of Fuel Behavior in Boiler - Results

- Combustion characteristics of H_2 rich fuel (H2RF) up to 36% H_2, are quite similar to the base case
    - [redacted]
    - [redacted]
- Post processing of simulation results show the lack of tendency of flashback, in accordance with the fact that the case here is not premixed combustion.

Outline

Broad List of Permit Required for the Project (1/2)

Permit Description	Permit or Authorization	Estimated Review /Approval Time (Months)	Responsible Party
Federal and State Permits and Authorizations			
Air Permit for Construction	Prevention of Significant Deterioration of Air Quality (PSD Permit)	9 months minimum for IDEM approval.	Owner
Nucleonic Level Devices	Registration	TBD	Owner
FAA Notice of Proposed Construction Form 7460-1	Notification	3 months, as applicable	Contractor
Biological and Cultural			
Water Quality Review	Indiana Department of Environmental Management (IDEM)	3 months minimum	Owner
Regional and Local Permits and Authorizations			
Final Building Permits	Indiana Department of Homeland Security	6 months	Contractor
Temporary Construction & Building Permits	Indiana Department of Homeland Security	6 months	Contractor
Tall structure construction	Indiana Department of Transportation	6 months	Owner

Broad List of Permit Required for the Project (2/2)

Permit Description	Permit or Authorization	Estimated Review /Approval Time (Months)	Responsible Party
Water			
Water Discharge Permit for Construction	Indiana Department of Environmental Management (IDEM)	N/A	Contractor
New/Modified Drainage Permit	Indiana Department of Environmental Management (IDEM)	1 month, as applicable	Owner
Waste Water Treatment	Indiana Department of Environmental Management (IDEM)	Notification only, as applicable	Owner
Waste Water permit	Indiana Department of Environmental Management (IDEM)	Notification only, as applicable	Owner
Waste			
UIC Permit- Class VI Wells	EPA	3-4 years	Owner

Constructability Review of BF Gas Pipe Tie-in

Total estimated time of activity (4) to (7) – 5 days when BFG pipeline will be shutdown

Outline

Environment Matrix

Projected Gaseous Emissions After Controls in TPY (tons per year)

Projected Water Emissions Load in pounds/day

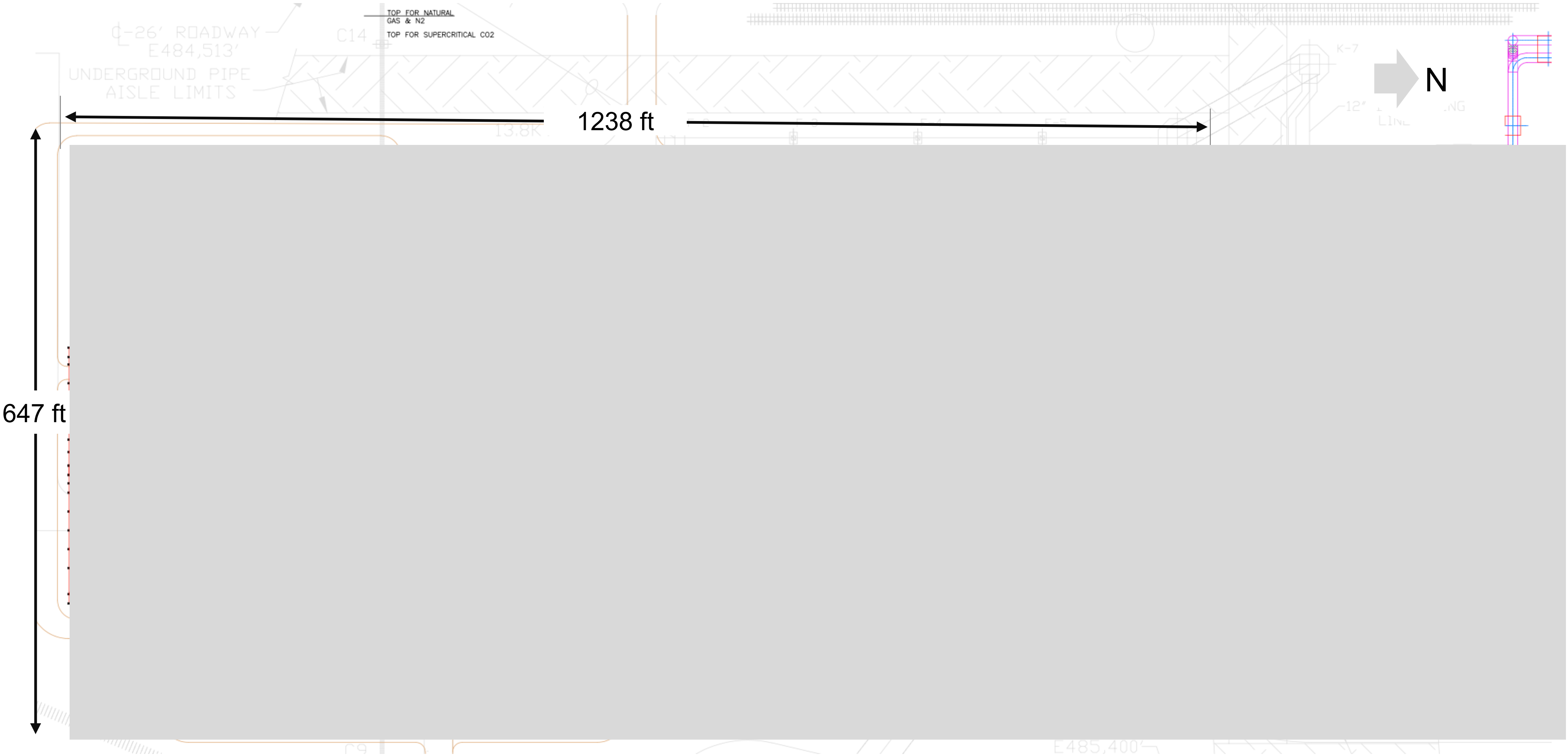
Projected solid waste disposal – About 450 cubic meter WGS degraded catalyst to be disposed once in 4 yr. It will be sold to a third party that recycle the catalyst of treatment

Major Risks Identified in Pre-HAZOP

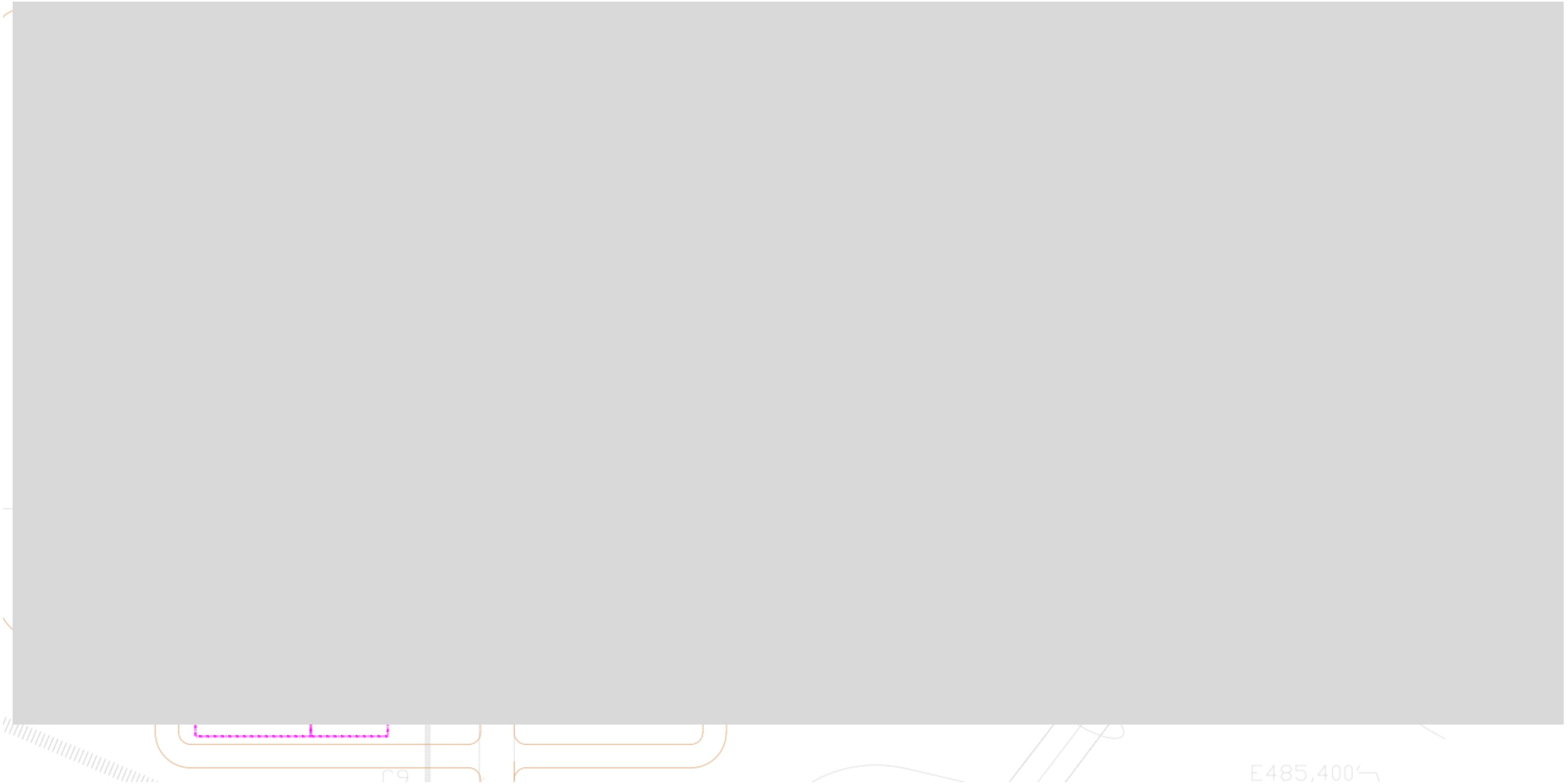
System	Deviation	Cause	Consequence	Safeguard	Action/Recommendation
General	Line Failure	Mechanical part malfunction			
BFG compressor	Seal Failure	Primary seal leakage			
Absorber	Pressure HH	LP CO2 cooler leakage			
CO_2 compression	Seal Failure	Primary seal leakage			
CO_2 pumps	Pump Failure	Material/seal failure			
Condensate Circuit	Low-pressure Boiler blasting	Release of Hot water/Steam/Metal parts			

Outline

Relative Disposition of Project Area



Layout of Project Area



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